A Large Coal IGCC Power Plant

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In late 1999, the National Energy Technology Laboratory awarded Nexant Inc. (a Bechtel-Affiliated Company) and Global Energy, Inc. (which acquired the gasification related assets of Dynegy Inc., of Houston, Texas including the E-GAS™ gasification technology, formerly the Destec Gasification Process) a contract to optimize IGCC plant performance.[6] Task 1 of this contract developed optimized IGCC plant configurations: (1) petroleum coke gasification for electric power with/without the coproduction of hydrogen and industrial-grade steam, and (2) coal gasification for electric power generation only. Figure 1 is a schematic diagram of Task 1 showing the steps used to develop the various coal and petroleum coke IGCC plants. Future work will look at the both coal and petroleum coke gasification for electric power with the coproduction of liquid transportation fuels.

This paper describes the optimization and cost reduction techniques used, presents the design for a nominal 1,000 MW coal-fueled IGCC power plant, and compares plant performance with the Wabash River Repowering Project and an improved single-train IGCC power plant design.

The Wabash River Coal Gasification Repowering Project

In 1990, Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana formed the Wabash River Coal Gasification Repowering Project Joint Venture to participate in the Department of Energy's Clean Coal Technology Program by demonstrating the coal gasification repowering of an existing 1950's vintage generating unit. In September 1991, the project was selected by the DOE as a Clean Coal Round IV project to demonstrate the integration of the existing PSI steam turbine generator and auxiliaries, a new combustion turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the DOE.[7] Under terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture developed, constructed and operated the coal gasification combined cycle facility. The DOE provided cost-sharing funds for construction and a three-year demonstration period.

The participants jointly developed, separately designed, constructed, owned, and operated the integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The gasification process integrated a new General Electric 7FA combustion turbine generator and a heat recovery steam generator (HRSG) to repower the 1950s-vintage Westinghouse steam turbine generator using some of the pre-existing coal handling facilities, interconnections, and other auxiliaries.

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[6] Contract No. DE-AC26-99FT40342, "Gasification Plant Cost and Performance Optimization"
[7] Contract No. DE-FC21-92MC9310, "Wabash River Coal Gasification Repowering Project"

Commercial operation of the facility began late in 1995. Within a few months, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance while using locally mined high sulfur Illinois Basin bituminous coal.[8] However, the first year of operation resulted in only a 35% annual availability, with over one half of the outage time being attributable to the dry char particulate removal system which experienced frequent failures of the ceramic candle filters. The facility has modified the particulate removal system including the use of metallic filters and has made significant improvements in other areas such as COS catalyst durability, chloride removal, and ash deposition control. As a result, step improvements in production were made during the second and third years of commercial operation. During the third year, operations were demonstrated on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. This ability to blend coal feedstocks has improved the fuel flexibility of the site. Additionally, two successful tests using petroleum coke (including one from a refinery processing Mayan crude) were completed in November 1997 and September 1999 further demonstrating the fuel flexibility of the technology. At operational rates of about 2,000 TPD of petroleum coke, over 250 MW of power was generated from the gas turbine combined cycle power plant while meeting all emission criteria.[9]

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.99 percent pure elemental sulfur and sold to sulfur users. Slag is being marketed for use as an aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

In 1998, the plant surpassed milestones of 10,000 hours of coal operation, 1,000,000 tons of coal processed, and achieved 77% availability for the third year of commercial operations (excluding downtime attributed to the combined cycle power generation section and for alternative fuel testing).[10] During 2000 and 2001, the plant was fueled by delayed petroleum coke and operated with minimal problems and significantly improved on-stream performance.

The repowering project demonstrated the ability to run at full load capability (262 MW) while meeting the environmental requirements for sulfur and NOx emissions. Cinergy, PSI's parent company, dispatches power from the project with a demonstrated heat rate of 8,900 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Currently, the Wabash River Coal Gasification Repowering Project is the largest single-train gasification facility in the Western Hemisphere, as well as the cleanest coal fired plant of any kind in the world. Global Energy now owns and operates the facility, and has renamed the Destec Gasification Process as the E-GAS™ Technology for future applications.

Based on the Wabash River Coal Gasification Repowering Project, Global Energy, Bechtel and Nexant are contributing their combined design, engineering, construction, and operating expertise to develop optimized designs for state-of-the-art IGCC plants processing either coal or petroleum coke.

The Wabash River Greenfield Plant

The gasification optimization work began by reviewing and assessing data from the existing Wabash River Project facility. Using the existing plant as the basis, design and cost engineers adjusted the plant's scope – equipment, materials, and process operation – so that the Wabash River project design was

[8] Topical Report Number 7, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, November, 1996, http://www.netl.doe.gov/publications/others/topicals/topical7.pdf.

[9] Phil Amick, *Commercial Operation of the Wabash River Gasification Project,* AIChE Spring National Meeting, Session T9011, New Orleans, March 9, 2000.

[10] "Wabash River Coal Gasification Repowering Project, Final Technical Report", U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.

transformed into a greenfield IGCC design as shown in Step 1 of Figure 1. In Step 2, the coal plant was converted to a trigeneration facility using petroleum coke as fuel and producing electricity, hydrogen, and industrial-grade steam. Step 3 optimized the petroleum coke IGCC coproduction plant.

Figure 2 is a simplified block flow diagram showing the major process blocks in the Wabash River Project Greenfield Plant developed in Step 1. Table 1 shows the coal properties and the major feed and product rates for the plant.

Capital cost is a key part of IGCC economics and profitability. The following three-stage cost estimating methodology was employed to develop a mid-year 2000 total installed cost for a greenfield plant equivalent to the Wabash River Coal Gasification Repowering Project, but located at a generic site in a typical Mid-Western state.

- **Derive a Cost Database from the Existing Wabash River Project Facility.** The initial cost database was set up using the documented equipment and construction material prices from the Wabash River Coal Gasification Repowering Project. The actual costs from the project were adjusted to eliminate the impact of unusual circumstances and escalated to today's values. The costs of any required equipment and materials that were not part of the new scope (such as the existing facilities; i. e., the repowered steam turbine), were added to the cost database.

- **Evaluate Changes and Incorporate the Effects of Changes into the Capital and Operating Costs.** Modifications to major pieces of equipment required during the demonstration period were considered, and, if necessary, new cost quotes were obtained. One example of this is the previously mentioned change from ceramic candle filters to metallic ones. The Bechtel estimating tool, COMET, was used to benchmark the bulk material quantities and to provide a basis for evaluating future changes. This tool enabled the study team to alter the plant layout as a result of process improvements, equipment size changes, etc., and to determine the net effect on piping and other bulk material quantities.

- **Develop a Method for Adjusting Base Case Capital Costs to Estimate Other Design Configurations.** Evaluations of alternate plant configurations required a standard methodology for estimating the resulting capital costs. The format for this estimating tool was developed based on historical data, escalation indices and vendor quotes and was employed on the subsequent tasks.

The Non-optimized Petroleum Coke IGCC Coproduction Plant

The petroleum coke IGCC coproduction plant studies including a financial analysis have been previously described.[11] However, They are summarized here.

In Step 2 the stand-alone coal-based Wabash River Greenfield Plant was reconfigured to use coke and produce power, steam, and hydrogen for an adjacent petroleum refinery and was moved to the U. S. Gulf Coast. Gasifier performance on petroleum coke is based on the demonstrated performance of the Wabash River facility when processing petroleum coke.

The basis for the design of the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant was that the steam and hydrogen co products that it produces must have a high reliability and are sold to the

[11] Amick, P. et. al., "An Optimized Petroleum Coke IGCC Coproduction Plant," Gasification Technologies Council Conference, San Francisco, CA., October 7-10,2001.

adjacent petroleum refinery. Since this plant now becomes an integral part of the petroleum refinery, it must be highly reliable since unexpected outages can have severe economic consequences to the refinery operations. Because a single gasification train with backup natural gas firing can satisfy the refinery steam and hydrogen requirements by sacrificing electric power production, all critical parts of the plant were replicated to provide high reliability of a single gasification train. For example, the slurry preparation and slurry storage areas each contain two duplicate trains with each train having sufficient capacity for the entire plant. The entire gasification area from the slurry pumping and heating sections to the acid gas removal area, including the sulfur recovery facilities, and hydrogen production facilities consist of three duplicate trains each with a capacity of 50% of the total plant design capacity. Figure 3 is a simplified block flow diagram of the non-optimized plant showing the major processing areas and major process streams between processing areas. The processing functions in the balance of plant area, such as makeup water treatment, are not shown. Figure 4 is a train diagram of the plant showing the replication of the major plant sections.

Thus, starting from the greenfield plant of Step 1 and location adjustments, the plant was enlarged and re-engineered to process petroleum coke, rather than coal, to produce hydrogen and industrial-grade steam in addition to electric power from two base loaded GE 7FA combustion turbines.. This plant is located at a generic Gulf Coast site adjacent to a large petroleum refinery. The plant consumes 5,249 TPD of dry petroleum coke and produces 395.8 MW of export electric power, 79.4 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750°F steam, and 367 TPD of sulfur. It also produces 99.6 MMscfd of a low Btu fuel gas (87 Btu/scf HHV) for the adjacent petroleum refinery. Table 1 shows the coke properties and the feed and product rates for the non-optimized petroleum coke IGCC coproduction plant.

The Subtask 1.2 plant uses two GE 7FA gas turbines; the same gas turbine as used at the Wabash River facility. A current, more efficient steam turbine that was optimized for this application was used. New petroleum coke receiving and storage facilities were designed to replace the coal facilities. New fresh water treatment facilities, a cooling water recirculation loop, and a cooling tower were added to replace the once through cooling water system. New waste water cleanup facilities also were designed to allow compliance with water discharge criteria and commingling of waster water with the refinery waste water outfall.

The mid-year 2000 installed cost of the non-optimized petroleum coke IGCC plant is 993.2 MM$. All installed plant costs cited in this paper are EPC costs which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).[12] They also assume that process effluent discharges are permitted.

The Optimization Process

After Steps 1 and 2 were completed, the next step was to optimize the petroleum coke IGCC plant. Process and project optimization was guided by Bechtel's Value Improvement Practices (VIPs) methodology using the following VIPs:

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Process Reliability Modeling
- Design-to-Capacity
- Predictive Maintenance
- Traditional Value Engineering
- Constructability and Schedule Optimization

[12] These excluded items are included in the subsequent discounted cash flow financial analysis.

Initially, Bechtel and Global Energy prepared a Value Improvement Plan. This plan determined that the above practices were most applicable to this study. "Champions" were assigned to each applicable practice, and these champions along with the Value Improvement Plan administrator were responsible for implementation of the VIP process as well as documenting the results. Bechtel and Global Energy thoroughly analyzed the Value Engineering ideas generated during the brainstorming sessions to determine which were applicable for improving the project by assessing their benefits.

The VIP efforts were concentrated in the gasification area, specifically on the gasification and waste heat recovery section, the particulate removal section, the raw gas cooling area, and the syngas cleanup area. Lessons learned from plant operations showed that these areas are critical to reliable operations and high on-stream factors. In the Traditional Value Engineering VIP, almost 300 different ideas were generated in several brainstorming sessions. These ideas are based on (1) actual operations and maintenance experience at the Wabash River plant, (2) construction of the Wabash River Repowering Project, and (3) Bechtel's experience in other gasification and power generation projects with similar equipment. Personnel from the Wabash River facility proposed many of these ideas.

In conjunction with the Value Improvement Plan, Bechtel used the COMET plant layout program to evaluate and optimize equipment layout arrangements and minimize piping requirements for a given area or between areas. By changing the location of any piece of equipment in a given area, COMET readjusts the interconnecting piping and recalculates new quantities. This optimization tool is especially beneficial in cases where a large percentage of the piping is large bore or high cost alloy material. Additionally, the COMET program also is capable of automatically generating plot plans and three-dimensional architectural renderings of the plant.

For several years now, Bechtel has been optimizing the heat integration of their standard coal and gas-based power plant designs. As a consequence, Bechtel has developed a *Powerline* suite of templates for combined cycle, pulverized coal, and fluidized bed power plant designs.[13] These *Powerline* plants incorporate the most advanced technologies and best practices from Bechtel's engineering portfolio. Designing plants using standard templates saves engineering and procurement costs resulting in higher quality plants that are less expensive and require less time for construction. The lessons learned during the development of the *Powerline* templates also were applied to optimize the various subtask designs.

Bechtel has created a number of supplier alliances, not only for major equipment manufacture and fabrication, but also for bulk materials. In addition to reducing the price of equipment, these alliances also shorten the engineering and procurement cycle resulting in shorter overall project schedules and reduced EPC costs which translate into faster payback and increased profitability. These ideas also were applied to optimize the designs.

Table 2 lists some of the major design improvements and changes that resulted from the application of the Value Improving Practices to the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant design to generate the optimized Subtask 1.3 plant design.

The Optimized Petroleum Coke IGCC Plant

Several design variations were examined during the development of the Optimized Petroleum Coke IGCC Plant. The most economically attractive of these is the one that is called the Next Optimized Petroleum Coke IGCC Coproduction Plant, or simply the Next Plant. This design is a modification of the Spare Gasification Train Plant that has been previously described.[11]

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[13] *Powerline* is a registered trademark of the Bechtel Corporation.

The Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction also is located on the Gulf Coast adjacent to a petroleum refinery. In addition to the VIP items listed in Table 2, the following additional design changes were made for the optimized plant.

1. Newer GE 7FA+e combustion turbines with a higher capacity of 210 MW each and a higher thermal efficiency with lower NOx and CO emissions replaced the GE 7FA turbines.
2. The low Btu fuel gas is no longer exported to the refinery, but instead is consumed internally to make high pressure steam which is used to make additional electric power.
3. Redundant equipment was removed unless it was shown to be economically advantageous to retain the extra equipment for increased reliability.
4. The hydrogen plant was redesigned to be more efficient with improved heat recovery.

The major processing areas and major interconnecting streams for the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant are the same as those shown in Figure 3 for the non-optimized Subtask 1.2 plant. Figure 5 is a train diagram of the Next Plant showing the replication of the major plant sections. Table 3 summarizes the Subtask 1.3 major plant input and output streams and compares them with those of the non-optimized plant. The optimized plant consumes 5,417 TPD of dry petroleum coke (about 5% more than the non-optimized plant) while using about the same size Air Separation Unit and produces 584.3 MW of gross power; 420 MW from the two combustion turbines and 164.3 MW from the steam turbine. It exports 474 MW of net electric power (almost 20% more than the non-optimized plant) while producing the same amount of hydrogen and steam. The increased export power production is attributable to a more efficient design, to higher performance equipment, and to the internal use of the low Btu fuel gas to make additional high pressure steam.

Compared to the non-optimized plant design, the amount of redundant equipment has been significantly reduced.

- The slurry preparation area was reduced to two 50% trains with two 60% rod mills compared to the non-optimized case which has two 100% trains.
- The three 50% trains in the low temperature heat removal (LTHR), acid gas removal (AGR), and sour water treatment areas were reduced to two 50% trains for the LTHR and AGR areas, and a single 100% sour water treatment area.
- The CO shift and PSA (hydrogen production area) contains two 50% trains compared to three in the non-optimized plant. The hydrogen compression area still contains three 50% hydrogen compressors because of their relatively high maintenance requirements.
- The three 50% trains in the sulfur recovery unit (SRU), hydrogenation, and tail gas recycle areas were reduced to two 50% trains for the optimized plant.
- Minor reductions of replicated and unnecessary equipment were made in other areas.

During the Value Improving Practices procedures, Process Availability Modeling studies suggested that an alternate case could be better than this base case depending upon the costs of replicating the gasification train and/or the gasification reactor vessels. Therefore, the above case is designated as the base case, and three alternate cases were developed. The Next Plant case, shown in Figure 5, turned out to be the best of these alternate cases.

Because of the various improvements incorporated the Subtask 1.3 design, less scheduled maintenance is required than at the Wabash River facility, and the scheduled outage periods can be shortened from twenty days to two weeks. Thus, the expected annual maintenance per train consists of only two two-week periods, or only four weeks per year.

Another change implemented in the optimization process was the use of full slurry quench in the gasifer second stage rather than using recycled syngas. This change improves the gasifier efficiency because it utilizes the heat in the syngas to promote the gasification reactions and saves the power needed to recycle the syngas.

Other significant design changes from the Subtask 1.2 design involve the syngas processing. In Subtask 1.2, the hot syngas leaving the gasifier goes to a hot residence vessel to allow further reaction. Following this, it is cooled in the high temperature heat recovery (HTHR) section, and dry char filters remove particulates. In the Subtask 1.3 Next Plant, the post reactor residence vessel has been eliminated, and the hot syngas goes directly to the HTHR section. Following this, most of the particulates (98+%) are removed from the syngas by a hot gas cyclone. Dry char filters remove the remaining particulates. In both cases, a wet scrubbing column downstream of the dry char filters removes water soluble impurities from the syngas.

Emissions performance of the non-optimized and Optimized Petroleum Coke IGCC Coproduction plants are similar as shown in Table 4. The reduced NOx and CO emissions of the optimized plant are the result of diluents injection and replacing the GE 7FA combustion turbine with the newer GE 7FA+e gas turbine which has both a higher power output and a higher thermal efficiency.

The mid-year 2000 installed cost of the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant is 787 MM$, about 21% less than the non-optimized plant. Although both the Subtask 1.2 and Subtask 1.3 Next Plant costs are mid-year 2000 costs, the Subtask 1.3 costs are more reflective of current market pricing. For the Subtask 1.3 plant, current vendor quotes were obtained for most of the added and high cost equipment. Power block costs are based on the actual costs of a similar power project, reflecting current market conditions. Because of the current demand for combustion turbines, the cost of the two turbines appears high compared to historical data.

If the three-train Subtask 1.2 plant were to be built using the Subtask 1.3 optimized gasification train design, that plant would cost about 880 MM$. This is a savings of 113 MM$ or just over 11%, essentially all of which is in the gasification and balance of plant areas.

The Single-Train Coal IGCC Power Plant

In Step 5, the design for a single-train coal-fueled IGCC power plant was developed based on the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant. However, this coal-fueled power plant design was developed from an intermediate Subtask 1.3 case, and not from the Next Plant case.

In the Subtask 1.5A Single-Train Coal-Fueled IGCC Power Plant design, the hot syngas leaving the gasifier goes to a hot residence vessel to allow further reaction. Following this, it is cooled in the high temperature heat recovery (HTHR) section before most of the particulates (98+%) are removed from the syngas by a hot gas cyclone. The remaining particulates and water soluble impurities, as well, are removed simultaneously by wet scrubbing with water. The particulates are concentrated and recovered from the wash water by a filter system before being recycled to the gasifier for further reaction. Filtered water is recycled to the wet scrubber or is sent to the sour water stripper. This particulate removal system is more expensive and energy intensive than the completely dry system particulate removal system that was developed subsequently and is used in the Subtask 1.3 Next Plant design.

Figure 6 is a train diagram of the Subtask 1.5A Single-Train Coal IGCC Power Plant showing the replication of the major plant sections. It consumes 2,335 TPD of dry Illinois No. 6 coal and produces 284.6 MW of export power, 60 TPD of sulfur, and 364 TPD of slag. The plant has a heat rate of 8,717 Btu (HHV)/kW-hr, or a 39.1% thermal efficiency (HHV). The plant cost 375 MM$ (mid-year 2000) or 1,318 $/kW of export power.

Table 5 compares the Subtask 1.5A Single-Train Coal IGCC Power Plant with the Subtask 1.1 Wabash River Greenfield Plant. The plant costs over 75 MM$ less than the Greenfield Plant and produces more export power showing the effect of the improvements that were made as the result of the optimization process and the larger and more efficient combustion turbine. On a $/kW basis, the Subtask 1.5A plant costs over 22% less than the Subtask 1.1 plant. Furthermore, the Subtask 1.5A plant is less polluting than the Wabash River Greenfield Plant. On a lb/MW-hr basis, SO_2 is reduced by 56%, CO is reduced by 33%, and NOx is reduced by 60%. Sulfur removal is increased from 96.8% to 98.5%.

The Nominal 1,000 MW Coal IGCC Power Plant

The Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant essentially is a four gasifier / four gas turbine version of the above Subtask 1.5A plant, but with the other sections of the plant reduced to either two or three trains to take advantage of the economy of scale. Figure 7 is a train diagram of the 1,000 MW coal plant showing the train replication. In addition, some other additional improvements were made to reduce the cost and increase the efficiency. The plant contains three air separation units. Two oversized slurry preparation trains feed four gasification blocks, each of which contains a slurry feed area, gasification reactor, high temperature heat recovery (HTRU) section, and a two-stage dry particulate removal area. This two-stage dry particulate removal area is the same as that used in the Subtask 1.3 Next Plant, a cyclone followed by a dry filtration system. The filtered syngas is cleaned and conditioned in a two train system consisting of a wet scrubber, low temperature heat recovery (LTHR) area, COS hydrolysis, and acid gas (sulfur) removal. The two acid gas removal systems feed two sulfur recovery plants. The cleaned syngas is divided between four General Electric 7FA+e combustion turbines, each with a heat recovery steam generator (HRSG). Two 233 MW steam turbines complete the power block.

Table 6 shows the major design parameters for the Subtask 1.6 Coal IGCC Plant Plant and compares them to two single-train IGCC coal power plants: the Subtask 1.1 Wabash River Greenfield Plant and the Subtask 1.5A IGCC Coal Power Plant. The Subtask 1.6 coal IGCC power plant consumes 9,266 TPD of dry Illinois No. 6 coal and produces 1,154.6 MW of export power, 237 TPD of sulfur, and 1,423 TPD of slag. The plant has a heat rate of 8,526 Btu (HHV)/kW-hr, or a 40.0% thermal efficiency (HHV). The plant cost 1,231 MM$ (mid-year 2000) or 1,066 $/kW of export power.

The emissions performance of the Subtask 1.6 optimized plant is significantly improved over the Wabash River Greenfield plant. On a per unit of power produced, the CO and NOx emissions from the Subtask 1.6 plant are about the same as the Subtask 1.5A plant because they both use the same GE 7FA+e gas turbine. However, the Subtask 1.6 plant has slightly lower sulfur emissions because of the dry particulate removal system. Table 6 provides a detailed breakdown of the air emissions from the Subtask 1.6, 1.1 and 1.5A plants. All three plants discharge both clear water (from the balance of plant facilities consisting of blowdown from the cooling towers, discharge from the fresh water purification facilities, and storm water) and a lesser amount of process water (from the gasification area).

Availability

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[14] During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After adjustments, this data was used to estimate the availability of the IGCC Plant designs. Using the EPRI recommended procedure, availability estimates were calculated for the Subtask 1.6 plant both as

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[14] "Wabash River Coal Gasification Repowering Project, Final Technical Report," U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.

only a coal fueled facility and when backup natural gas is used to fire the combustion turbines when sufficient syngas is unavailable.[15]

Table 7 presents the design (stream day) and average daily (calendar day) feed and product rates for the Subtask 1.6 1,000 MW Coal IGCC Power Plant, both with and without the use of backup natural gas, the Subtask 1.1 Wabash River Greenfield Plant, and the single-train Subtask 1.5A Coal Power Plant. As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and for the coal feed rates. Both the Subtask 1.1 and 1.5A single-train plants have a spare gasifier vessel in their gasification trains whereas the four-train Subtask 1.6 plant does not contain any spare gasification vessels.

The Subtask 1.6 plant has a daily average power production rate from syngas of 874.5 MW or about 75.7% of the design capacity. This is slightly better than the average power production capacity from syngas for the Subtask 1.1 plant of 75.5% even though it contains a spare gasification vessel. The improved capacity factor is the direct result of the design improvements developed during the VIP exercise. The power production capacity from syngas for the Subtask 1.5A plant is the highest at 78.2% because of the design improvements and the spare gasifier vessel which allows for the periodic refractory replacement in the off-line vessel while the plant is operating.

With the use of backup natural gas, the capacity factor of the Subtask 1.6 plant increases to 1,081 MW or 93.6%, which is just above the 93% capacity factor of the Subtask 1.5A plant with backup gas.

Discounted Cash Flow Financial Analysis

A financial analysis was performed using a discounted cash flow (DCF) model that was developed by Nexant Inc. (formerly Bechtel Technology and Consulting) for the DOE.[16] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects.

The first line of Table 8 shows the required power selling prices that will produce an after-tax ROI of 12% for the three IGCC coal to power plants with a coal price of 22.0 $/ton dry (0.86 $/MMBtu). (The other basic economic parameters are shown in the middle column of Table 9.) With a 10% loan interest rate and without natural gas backup, the four-train Subtask 1.6 1,000 MW Coal IGCC Power Plant has the lowest required power selling price of 44.4 $/MW-hr (or 4.44 cents/kW-hr) to produce a 12% after-tax return on investment. The single-train Subtask 1.5A Coal to Power Plant requires a 53.9 $/MW-hr power selling price, and the Subtask 1.1 Wabash River Greenfield Plant requires a 67.5 $/MW-hr power selling price for a 12% after-tax return on investment.

With the use of 2.60 $/MMBtu backup natural gas to fire the combustion turbines when syngas is not available, the required power selling prices for a 12% after-tax return on investment are even lower. The Subtask 1.6 case now requires a power selling price of only 40.2 $/MW-hr, and the Subtask 1.5A coal case requires a power price of 48.9 $/MW-hr. Figure 8 shows the return on investment for the Subtask 1.6 and 1.5A plants, both with and without natural gas backup, and the Subtask 1.1 Wabash River Greenfield Plant as a function of the power selling price with a 10% loan interest rate. This figure graphically shows how the return on investment has increased as a function of the power selling price as a result of the design improvements and operational experience that have been made since the Wabash River Repowering Project was built.

[15] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA, August 1985.
[16] Nexant, Inc., "Financial Model Users Guide – IGCC Economic and Capital Budgeting Evaluation," Report for the U. S. Department of Energy, Contract No. DE-AM01-98FE64778, May 2000.

The calculated power selling price is 38.9 \$/MW-hr for a natural gas combined cycle power plant (costing 450 \$/KW of export power) with 3.00 \$/MMBtu natural gas using the same financial assumptions, but with a shorter construction period. At the same natural gas price, the coal-fired IGCC power plant will require a power selling price of 40.9 \$/MW-hr to produce a 12% ROI, about 2.0 \$/MWhr greater than that of the natural gas combined cycle plant. At a natural gas price of 3.22 \$/MMBtu, the natural gas combined cycle plant will require a power selling price of 40.9 \$/MW-hr in order to have a 12.0% ROI. These power selling prices are competitive with the 2001 EIA projections of an average electric selling price of just over 6 cents/kW-hr for the next two decades.[17]

Table 9 shows the sensitivity of some individual component prices and financial parameters for the Subtask 1.6 IGCC power plant starting from a 12% ROI (with a power price of 40.23 \$/MW-hr). Each item was varied individually without affecting any other item. Most sensitivities are based on a ±10% change from the base value except when either a larger or smaller change is used because it either makes more sense or it is needed to show a meaningful result. The power selling price is the most sensitive product price with a 10% increase resulting in a 5.79% increase in the ROI to 17.79%, and a 10% decrease resulting in a 6.53% decrease in the ROI to 5.47%. Changes in the sulfur and slag prices have only a small influence on the ROI.

A decrease in the coal price of 5 \$/ton from the base coal price of 22.0 \$/ton will increase the ROI by 1.94% to 13.94% and a 5 \$/ton increase in the coal price will lower the ROI by 1.98% to 10.02%. A decrease in the natural gas price of 0.26 \$/MMBtu from the base natural gas price of 2.60 \$/MMBtu will increase the ROI by 0.65% to 12.65% and a 0.26 \$/MMBtu increase in the gas price will lower the ROI by 0.66% to 11.34%.

A 5% decrease in the plant EPC cost to 1,170 MM\$ will increase the ROI by 0.33% to 12.33%, and a 5% increase in the plant cost to 1,293 MM\$ will decrease the ROI by 0.31% to 11.69%.

The loan interest rate has a very significant effect on the financial performance of the plant. A 20% decrease in the loan interest rate to 8% from the base interest rate of 10% will increase the ROI to 15.82% from 12.00%, and a 20% increase in the interest rate to 12% will lower the ROI to 8.07%. A 20% decrease in the loan amount from 80% to 72% will lower the ROI by 0.62% to 11.38%, and a 20% increase in the loan amount to 88% will increase the ROI by 1.06% to 13.06%. Decreasing the income tax rate by 10% from 40% to 36% will increase the ROI to 12.47%, and a 10% increase in the tax rate to 44% will lower the ROI by 0.51% to 11.49%.

If the plant performance can be increased by 2.5% by improving the thermal efficiency of the plant so that the daily average power output increases to 1,108 MW from 1,081 MW, then the ROI increases by 1.51% to 13.51%. Conversely, a 2.5% decrease in plant performance, which will reduce the daily average power output to 1,054 MW, will lower the ROI by 1.54% to 10.46%.

Effect of Loan Interest Rate

The second line of Table 8 shows the required power selling prices that will produce an after-tax ROI of 12% for the three IGCC coal to power plants with a 8% loan interest rate. As is the case with the 10% loan interest rate cases, there is an additional 3% financing fee on the amount of the loan. With a 8% loan interest rate and without natural gas backup, the Subtask 1.6 plant still has the lowest required selling price of 41.3 \$/MW-hr (or 4.13 cents/kW-hr) to produce a 12% after-tax return on investment. The Subtask 1.5A plant requires a 50.4 \$/MW-hr power selling price, and the Subtask 1.1 Wabash River Greenfield Plant requires a 62.9 \$/MW-hr power selling price for a 12% after-tax return on investment.

[17] Energy Information Administration, "Annual Energy Outlook With Projections to 2020," U. S. Department of Energy, Washington, DC, www.eia.doe.gov/oiaf/aeo, December, 2000.

With 2.60 $/MMBtu HHV backup natural gas, the required power selling prices are further reduced. The Subtask 1.6 case now requires a power selling price of only 37.8 $/MW-hr, and the Subtask 1.5A coal case requires a power price of 45.9 $/MW-hr. Figure 9 shows the return on investment for the Subtask 1.6 and 1.5A plants, both with and without natural gas backup, and the Subtask 1.1 Wabash River Greenfield Plant as a function of the power selling price with a 8% loan interest rate. This figure is similar to Figure 8, but a comparison with it shows how influential the loan interest rate is on the return on investment.

The calculated power selling price is 38.1 $/MW-hr for a natural gas combined cycle power plant with a GE 7FA+e combustion turbine (costing 450 $/KW of export power) with 3.00 $/MMBtu HHV natural gas using the same financial assumptions, but with a shorter construction period and an 8% loan interest rate. At the same natural gas price, the coal-fired IGCC power plant will require a power selling price of 38.4 $/MW-hr to produce a 12% ROI, slightly above that of the natural gas combined cycle plant. At a natural gas price of 3.04 $/MMBtu, the natural gas combined cycle plant will require a power selling price of 38.4 $/MW-hr in order to have a 12.0% ROI.

Effect of Syngas Availability

After commissioning all plants undergo a “learning curve” during which problem areas are corrected, inadequate equipment is modified and/or replaced, and adjustments are made. Consequently, performance improves as measured by increased capacity or improved on-stream factors. Figure 10 shows the effect of improved power availability from syngas on the required power selling price for a 12% ROI. As the syngas availability improves, the amount of supplemental natural gas is reduced causing the difference between the cases with and without natural gas to decrease. At the unattainable 100% power availability from syngas, there is no difference between the two cases.

Without natural gas backup, increasing the syngas power availability from 75.74% to 80% reduces the required power selling price for a 12% ROI by about 2.0 $/MW-hr from 44.4 to 42.4 $/MW-hr. With natural gas backup, the reduction is not as great, about 0.9 $/MW-hr from 40.2 to 39.3 $/MW-hr.

Figure 11 shows the effect of power availability from syngas on the return on investment without natural gas backup at a power selling price of 44.4 $/MW-hr. In this case, increasing the syngas availability from 75.7% to 80% increases the return on investment by about 2.5% from 12.0 to 14.5%. This figure points out the strong incentive for designing and building plants that will have high availability.

Alternate Design Case

For Subtask 1.6, the availability analysis showed that all four gasification trains would be operating simultaneously for only about 36% of the time because each gasification train does not contain a spare gasification vessel. Since each vessel will require refractory replacement about every other year which takes about three months, an alternate design case was considered to increase the amount of time when sufficient syngas will be available to fully power the gas turbines. In the Subtask 1.1 and 1.5A designs, a second gasification vessel was added to increase the syngas availability so that one vessel could be operating while the refractory in the other is being replaced.

A different approach was taken in this case; namely, that of increasing the capacity of each gasification train by 33.3% so that three gasification trains operating at full capacity will be able to provide sufficient syngas to fully load the four gas turbines. Thus, the capacity of each syngas train (from the slurry feed pumps through the gasification, high temperature heat recovery, and two-stage dry particulate removal areas) was increased by one-third. The sizes of the units in all the other areas of the plant were left unchanged. This redesign increased the time when sufficient syngas will be available for firing all four gas turbines from 36% to 42% with only a moderate cost increase in the plant cost of about 43 MM mid-2000 dollars. This is less than the cost of adding either an entire spare gasification train or a spare gasification reactor in each train.

Figure 12 shows the return on investment as a function of the power selling price for both the alternate design case (4 x 33% gasification trains) and the original case (4 x 25% gasification trains) with a 10% loan interest rate. The use of the larger trains significantly increases the return on investment at a given power price. At a 40 \$/MW-hr power price, the ROI increases from 6.55% to 12.03% for the cases without backup natural gas. With backup natural gas, the increase is not as great, only about 2%, from 11.65% to 13.64%, and the required power selling price for a 12% ROI is 38.9 \$/MW-hr.

With an 8% loan rate, the required power selling prices are further reduced. For the case without backup natural gas, the required power selling price for a 12% ROI drops to 37.3 \$/MW-hr, and for the case with backup natural gas, it is 36.4 \$/MW-hr

Summary

A design was developed for a large coal-fueled IGCC power plant that processes 9,266 TPD of dry Illinois No. 6 coal and can produce 1154.6 MW of export power at an EPC cost of 1,231 million mid-year 2000 dollars or 1,066 \$/KW of export power. On a per unit of power basis, the emissions performance of the Subtask 1.6 plant is significantly better than the emissions performance of the Subtask 1.1 Wabash River Greenfield Plant and about the same as the single-train Subtask 1.5A IGCC Coal Power Plant.

The economics of this plant also are more favorable because of

- The Value Improving Practices that were employed in developing the design
- The use of a newer and larger GE 7FA+e combustion turbine
- Economies of scale

For a 12% return on investment without supplemental natural gas and with a 10% project financing rate, the required export power selling price dropped from 67.5 \$/MW-hr for the Subtask 1.1 Wabash River Greenfield Plant to 53.9 \$/MW-hr for the single-train Subtask 1.5A IGCC Coal Power Plant, and to 44.4 \$/MW-hr for the Subtask 1.6 power plant. Compared to the Subtask 1.1 Wabash River Greenfield Plant, this is a savings of over 34%. The use of supplemental natural gas will further reduce the required selling price to 40.2 \$/MW-hr for the Subtask 1.6 plant.

In today's current economic situation, an 8% interest loan with a 3% upfront financing fee may be possible. Under these conditions, the required export power selling price to produce a 12% ROI drops to 37.8 \$/MW-hr with the use of supplemental 2.60 \$/MMBtu HHV natural gas. Without supplemental natural gas the required power selling price is 41.3 \$/MW-hr. At these power prices, this coal-fired IGCC power plant can be competitive with new natural gas combined cycle power plants using 3.00 \$/MMBtu HHV natural gas.

Table 1
Plant Design and Operating Conditions

	Subtask 1.1 Wabash River Greenfield Plant		Subtask 1.2 Petroleum Coke IGCC Coproduction Plant	
Location	Typical Mid-Western State		U.S. Gulf Coast near a Petroleum Refinery	
Feedstock	Illinois No. 6 Coal		Green Delayed Petroleum Coke	
	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900	14,848	13,810
Analysis, wt %				
Carbon	69.9	59.76	88.76	82.55
Hydrogen	5.0	4.28	3.20	2.98
Nitrogen	1.3	1.11	0.90	0.84
Sulfur	2.58	2.21	7.00	6.51
Oxygen	8.27	7.07	-	-
Chlorine	0.13	0.11	50 ppm	47 ppm
V & Ni	-	-	1900 ppm	1767 ppm
Ash	12.7	10.86	0.14	0.13
Moisture	-	14.5	-	6.99
Total	100	100	100	100
Inputs				
Fuel, dry basis	2,260 tons/day		5,250 tons/day	
Makeup Water,	2,280 gpm		4,830 gpm	
Refinery Condensate	0		686,000 lb/hr	
Outputs				
Export Power, MW	269.3		396	
Slag, tons/day	356		190	
Sulfur, tons/day	57		367	
Hydrogen	0		79.4 MMscfd	
Purity	-		99 %	
Pressure	-		1000 psig	
Temperature	-		120^{o}F	
Steam	0		980,000 lb/hr	
Pressure	-		700 psig	
Temperature	-		750^{o}F	
Waste Water	120 gpm		30 gpm	

Table 2

Subtask 1.3 Major VIP and Optimization Items

Plant **Section**	Description
100	Simplified the solids handling system
150	Removed the slurry feed heaters and spare pumps
300	• Maximized the use of slurry quench in the gasifier second stage • Maximized syngas moisturization • Used a cyclone and wet particulate removal system rather than dry char filters to clean the syngas • Improved the burner design • Removed the post reactor residence vessel
400/420	Simplified the Claus plant, amine, and sour water stripper resulting in lower incinerator emissions
500	• Used a state-of-the-art GE 7FA+e gas turbine with 210 MW output and lower NOx • Combined syngas moisturization with use of the least cost diluent (steam) in the gas turbine
General	• Bechtel's Powerline cost and philosophy applied to an IGCC plant; i.e., a building block approach • Bechtel's MPAG (Multi Project Acquisition Group) was used to obtain low equipment and bulk material costs • Availability analysis was used to select design with maximum on-stream time • The COMET plant layout model was used to develop a compact plant layout and minimize amount of high cost and alloy piping. • Design features were added to reduce the O&M costs

Table 3
Design Input and Output Streams for the Non-optimized and Next Optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Next Optimized Plant
Plant Input		
Coke Feed, as received, TPD	5,515	5,692
Dry Coke Feed to Gasifiers, TPD	5,249	5,417
Oxygen Production, TPD of 95% O_2	5,962	5,954
Total Fresh Water Consumption, gpm	4,830	5,120
Condensate Return from the Refinery, lb/hr	686,000	686,000
Flux, TPD	107	110.6
Plant Output		
Net Power Output, MW	395.8	474.0
Sulfur, TPD	367	373.4
Slag, TPD (15% moisture)	190	195.1
Hydrogen, MMscfd	79.4	80
HP Steam, 700 psig/750^{o}F, lb/hr	980,000	980,000
Fuel Gas Export, MMscfd	99.6	0
MMBtu/hr, (HHV)	363	0

Table 4
Total Emissions Summary for the Non-optimized and Next Optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Next Optimized Plant
Total Exhaust Gas Flow Rate, lb/hr (see note)	7,588,700	8,602,300
Emissions		
SOx ppmvd	20	224
SOx as SO_2, lb/hr	306	350
NOx, ppmvd	30	14
NOx as NO_2, lb/hr	325	166
CO, ppmvd	17	15
CO, lb/hr	111	106
CO_2, lb/hr (see note)	1,019,074	1,443,400
VOC and Particulates, lb/hr	NIL	NIL
Opacity	0	0
Sulfur Removal, %	99.5	99.4

Note: The exhaust gas flow rate and CO_2 rate for the Subtask 1.3 next optimized plant include burning the low Btu PSA off gas to make high pressure steam, but for the non-optimized Subtask 1.2 plant, the low Btu PSA off gas is sold as fuel gas to the refinery.

Table 5
Comparison of the Subtask 1.1 Wabash River Greenfield Plant and the Subtask 1.5A Single-Train Coal IGCC Power Plant

	Subtask 1.1 Wabash River Greenfield Plant	Subtask 1.5A Single-Train IGCC PowerPlant
Location	Mid-West	Gulf Coast
Plant Input		
Dry Coal Feed, TPD	2,260	2,335
Oxygen Production, TPD of 95% O_2	2,130	2,015
Total Fresh Water Consumption, gpm	2,280	2,836
Plant Output		
Net Power Output, MW	269.3	284.6
Sulfur, TPD	57	60
Slag, TPD (15% moisture)	356	364
Emissions		
SO_2, lb/MW-hr	1.16	0.50
CO, lb/MW-hr	0.21	0.14
NOx, lb/MW-hr	0.60	0.24
VOC and Particulates, lb/hr	NIL	NIL
Opacity	0	0
Sulfur Removal, %	96.8	98.5
Performance		
Heat Rate, Btu/kW-hr	8,912	8,717
Thermal Efficiency, %HHV	38.3	39.1
EPC Cost,* million mid-2000 $	452.6	375
EPC Cost,* mid-2000 $/kW	1,680	1,318

* The EPC costs are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).

Table 6

Design Feed and Product Rates for the Subtask 1.6, 1.1 and 1.5A Coal IGCC Power Plants

	Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant	Subtask 1.1 Wabash River Greenfield Plant	Subtask 1.5A Single-Train IGCC Power Plant
Number of Gasification Trains	4	1	1
Total No. of Gasification Vessels	4	2	2
Number of Combustion Turbines	4	1	1
Feeds			
Coal, TPD dry	9,266	2,259	2,335
River Water, gpm	9,652	2,281	2,836
Products			
Power, MW	1,154.6	269.3	284.6
Sulfur, TPD	236.6	57	60
Slag, TPD	1,423	356	364
Performance			
Oxygen Consumption,			
TPD of 95% O_2	8,009	2,130	1,900
Tons O_2/ton dry coal	0.81	0.89	0.81
Water Discharge, gpm			
Process Water	59	120	72
Clear Water*	1,248	643	826
Total Discharge	1,307	763	898
Heat Rate, Btu (HHV)/kW	8,526	8,912	8,717
Thermal Efficiency, % HHV	40.0	38.3	39.1
Emissions			
SO_2, lb/MW-hr	0.38	1.16	0.50
CO, lb/MW-hr	0.14	0.21	0.14
NOx, lb/MW-hr	0.24	0.60	0.25
Sulfur Removal, %	99.0	96.7	98.5
Plant Area, acres	62	61	40
EPC Cost,+ million mid-2000 $	1231.3	452.6	375
EPC Cost, + $/KW	1,066	1,680	1,318

* Clear water discharge includes a 150 gpm allowance for storm water.

+ The EPC costs are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).

Table 7

Design and Daily Average Feed and Product Rates for the Subtask 1.6, 1.1 and 1.5A Coal IGCC Power Plants

	Subtask 1.6 1,000 MW Coal IGCC Power Plant			Subtask 1.1 Wabash River Greenfield Plant		Subtask 1.5A Single-Train IGCC Power Plant		
		Daily Average			Daily Average		Daily Average	
	Design	Without Backup Gas	With Backup Gas	Design	Without Backup Gas	Design	Without Backup Gas	With Backup Gas
Feeds								
Coal, TPD dry	9,266	7,018	7,018	2,259	1,705	2,335	1,826	1,826
Natural Gas, Mscfd	0	0	34,961	0	0	0	0	6,929
River Water, gpm	9,752	7,386	NC	2,281	1,722	2,836	2217	NC
Products								
Export Power, MW	1,154.6	874.5	1,081.0	269.3	203.2	284.6	222.5	264.4
Sulfur, TPD	236.6	179.2	179.2	57	43	60	46.9	46.9
Slag, TPD	1,423	1,078	1,078	356	281	364	284.6	284.6
Performance								
Oxygen Consumption,								
TPD of 95% O_2	8,009	6,066	6,066	2,130	1,608	2,015	1,576	1,576
TPD O_2/TPD dry coal	0.86	0.86	0.86	0.94	0.94	0.86	0.86	0
Water Discharge, gpm								
Process Water	59	45	45	120	91	72	56	56
Clear Water	1248	945	NC	643	485	640	500	NC
Total Discharge	1307	990	NC	763	576	712	557	NC
Heat Rate, Btu/kW	8,526	8,526	8,245	8,912	8,912	8,717	8,717	8,429
Thermal Efficiency, %	40.0%	40.0%	41.4%	38.3%	38.3%	39.1%	39.1%	40.5%
Emissions								
SO_2, lb/MW-hr	0.38	0.38	0.31	1.16	1.16	0.50	0.50	0.42
CO, lb/M-hr	0.14	0.14	NC	0.21	0.21	0.14	0.14	NC
NOx, lb/MW-hr	0.24	0.24	NC	0.60	0.60	0.24	0.24	NC
Sulfur Removal, %	98.9	98.9	98.9	96.8	96.8	98.6	98.6	98.6

Table 8

Required Power Selling Prices for a 12% Return on Investment

	Power Selling Price, in $/MW-hr				
	Subtask 1.6		Subtask 1.5A		Subtask 1.1
Loan Interest Rate	Without Natural Gas	With Natural Gas	Without Natural Gas	With Natural Gas	Without Natural Gas
10%	44.37	40.23	53.89	48.86	67.49
8%	41.34	37.77	50.39	45.92	62.87

Table 9

Sensitivity of Individual Component Prices and Financial Parameters on the Subtask 1.6 IGCC Power Plant Starting from a 12% ROI (with a Power Price of 40.23 $/MW-hr and with Backup Natural Gas)

	Decrease				Increase		
	ROI	Value	% Change	**Base Value**	% Change	Value	ROI
Products							
Power	5.47%	36.207 $/MW-hr	-10%	**40.23 $MW-hr**	+10%	44.253 $/MW-hr	17.79%
Sulfur	11.97%	27 $/t	-10%	**30 $/t**	+10%	33 $/t	12.03%
Slag	11.73%	-5 $/t	---	**0 $/t**	---	5 $/t	12.27%
Feeds							
Coal	13.94%	17 $/t	-23%	**22.0 $/t**	23%	27 $/t	10.02%
Natural Gas	12.65%	2.34 $/MMBtu	-10%	**2.60 $/MMBtu**	+10%	2.86 $/MMBtu	11.34%
Financial							
Plant Cost	12.16%	1200.5 MM$	-2.5%	**1231.3 MM$**	+2.5%	1262.1 MM$	11.84%
Plant Cost	12.33%	1169.8 MM$	-5.0%	**1231.3 MM$**	+5.0%	1292.9 MM$	11.69%
Interest Rate	15.82%	8%	-20%	**10%**	+20%	12%	8.07%
Loan Amount	11.38%	72%	-20%	**80%**	+20%	88%	13.06%
Tax Rate	12.47%	36%	10%	**40%**	+10%	44%	11.49%
Performance							
Average Power	10.46%	1054.0 MW	-2.5%	**1081.0 MW**	+2.5%	1108 MW	13.51%
Average Power	8.87%	1027.0 MW	-5.0%	**1081.0 MW**	+5.0%	1135.1 MW	14.97%

Figure 1

Schematic Diagram Showing the Chronological Development of the Gasification Plant Designs

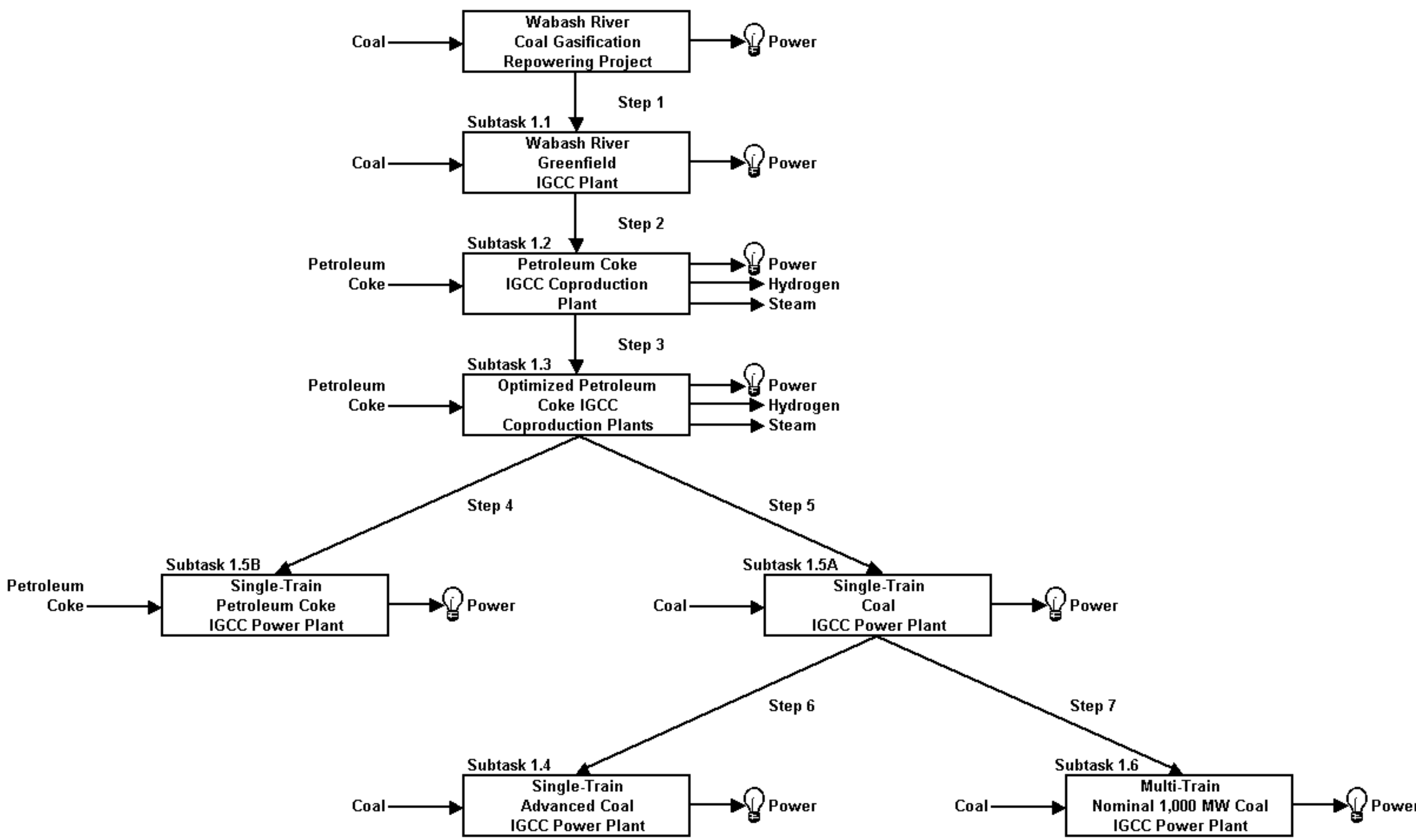
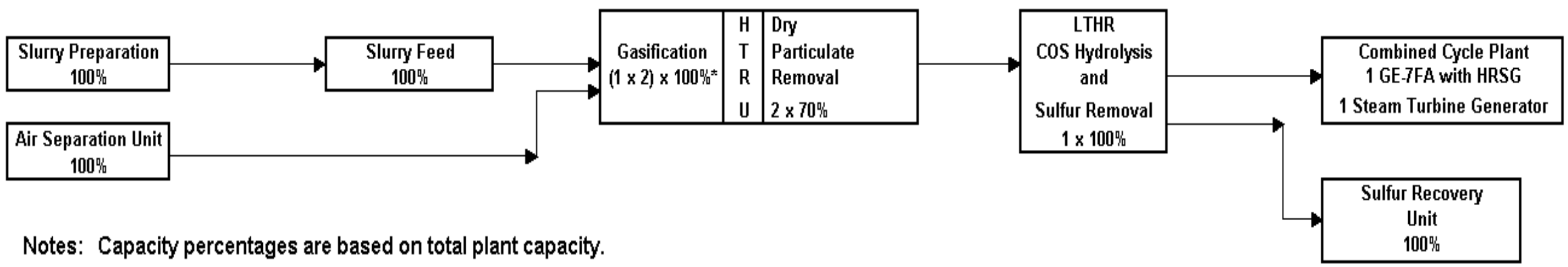


Figure 2

Wabash River Greenfield Plant

Block Flow (Train) Diagram



Notes: Capacity percentages are based on total plant capacity.

Figure 3

Petroleum Coke IGCC Coproduction Plant
Simplified Block Flow Diagram

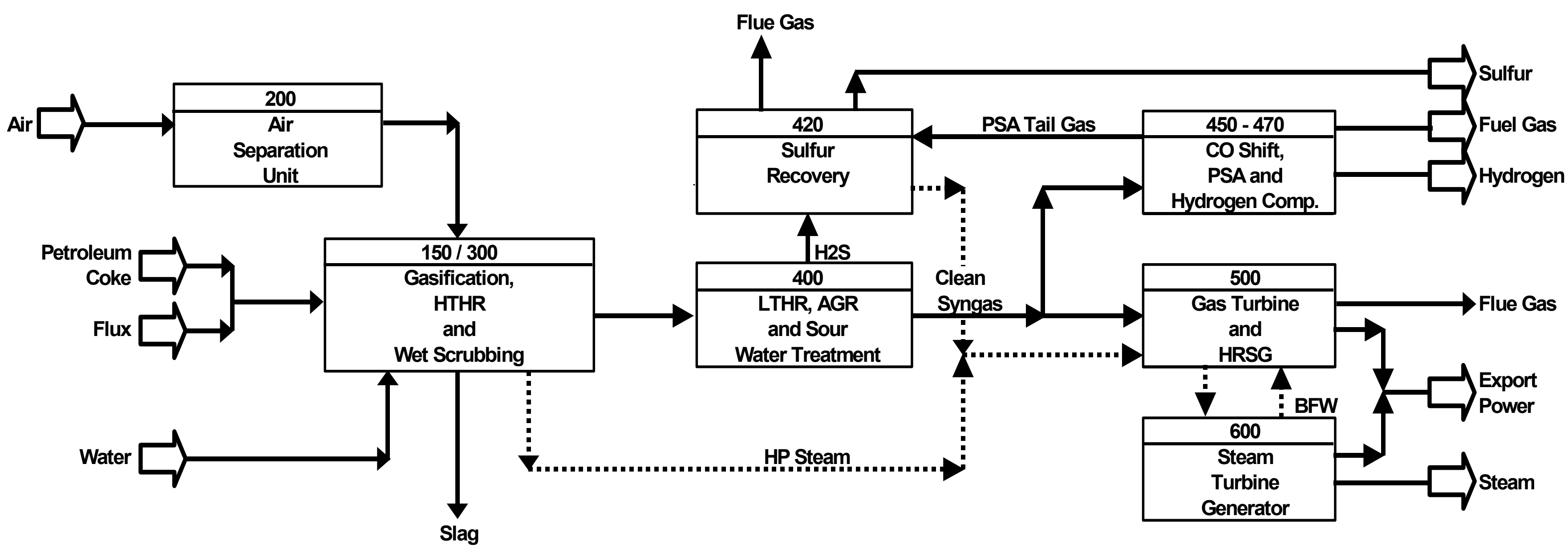


Figure 4

Subtask 1.2 - Block Flow (Train) Diagram

Non-optimized Petroleum Coke IGCC Coproduction Plant

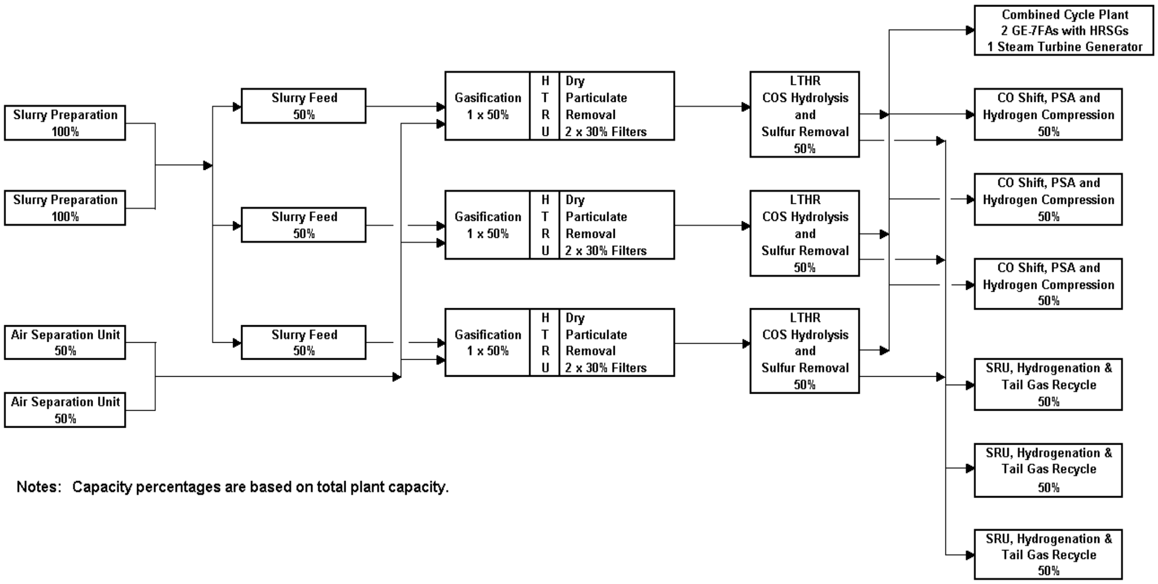
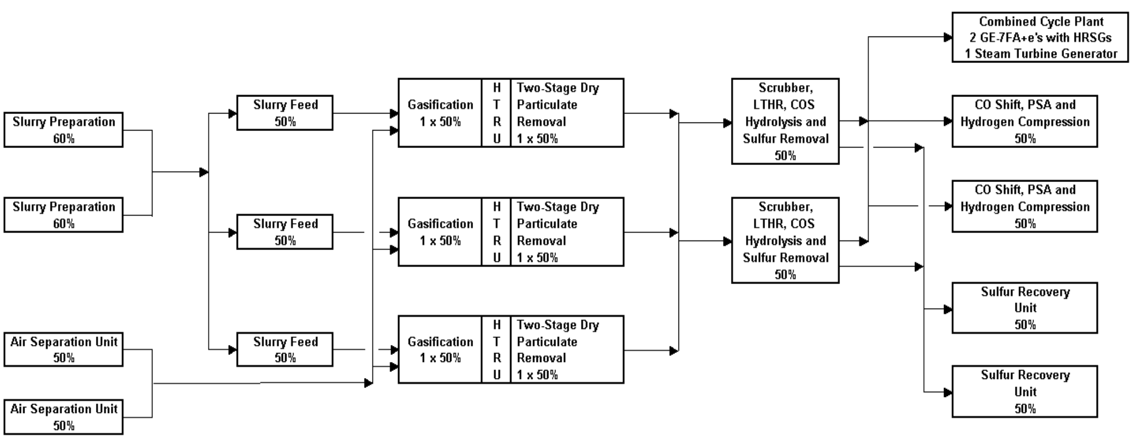


Figure 5

Subtask 1.3 Next Plant- Block Flow (Train) Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

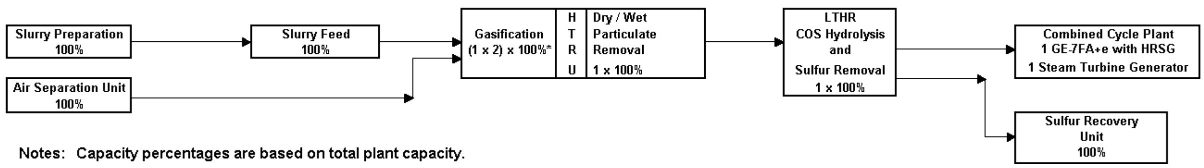


Notes: Capacity percentages are based on total plant capacity.

Figure 6

Subtask 1.5A - Block Flow (Train) Diagram

Single-Train Coal IGCC Power Plant

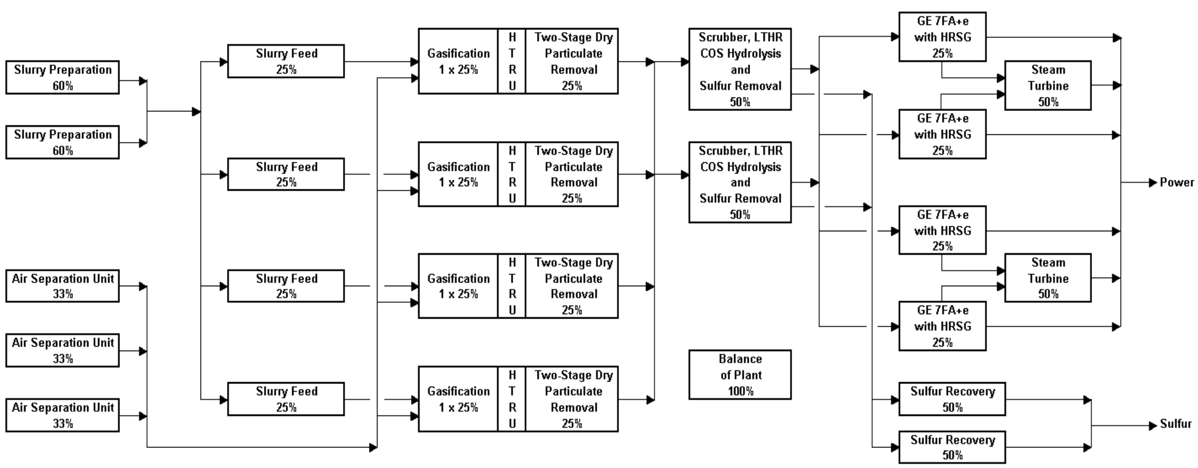


Notes: Capacity percentages are based on total plant capacity.

Figure 7

Subtask 1.7 - Block Flow (Train) Diagram

Nominal 1,000 MW Coal IGCC Plant



Note: Capacity percentages are based on total plant capacity.

Figure 8

Effect of Power Selling Price on the Return on Investment at a 10% Loan Interest Rate

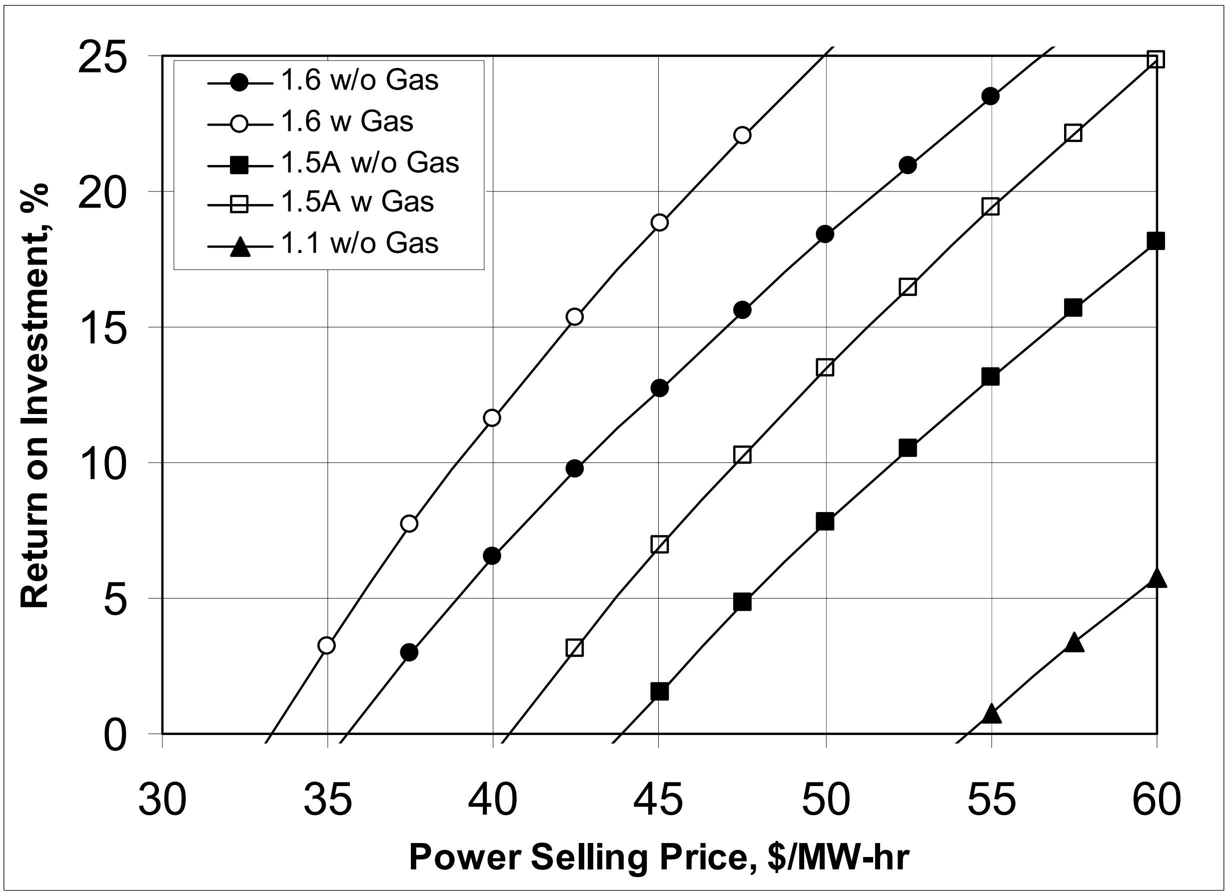


Figure 9

Effect of Power Selling Price on the Return on Investment at a 8% Loan Interest Rate

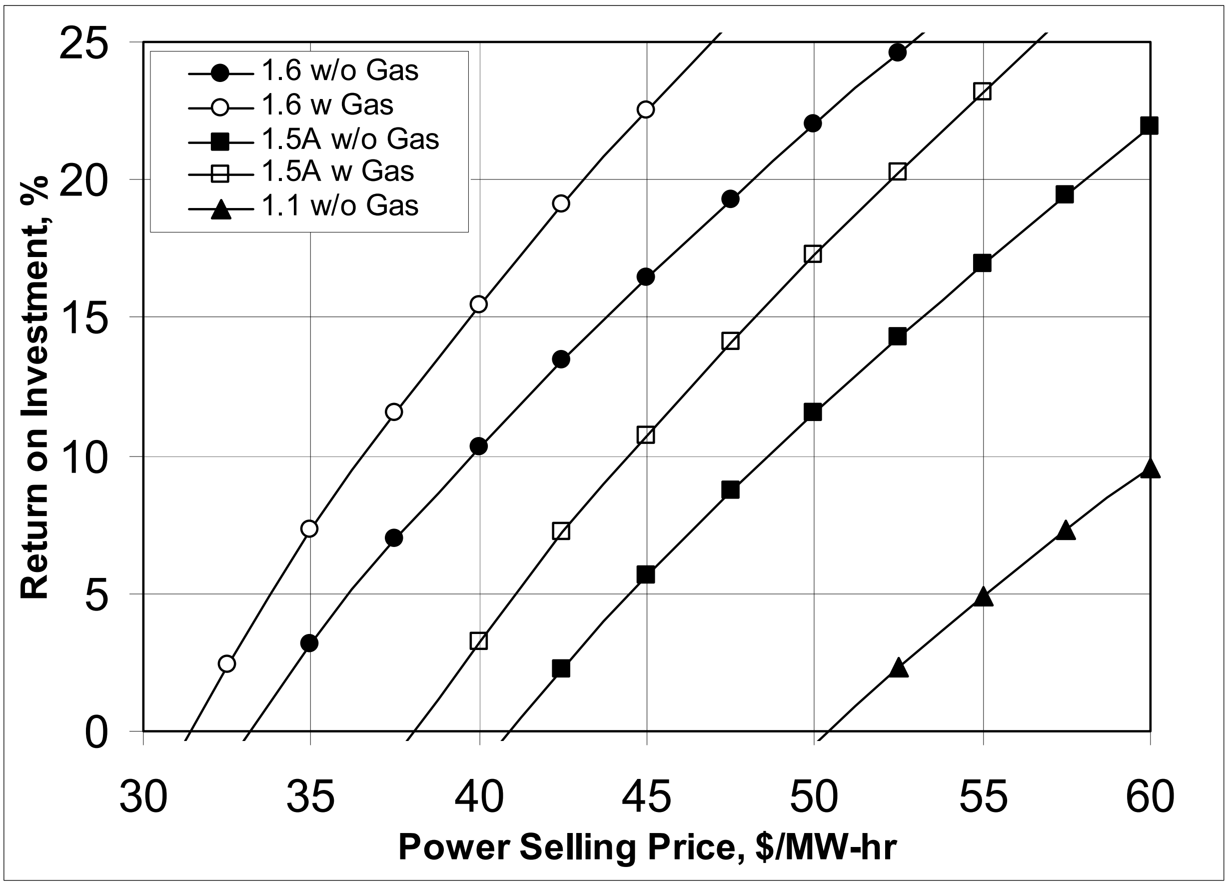


Figure 10

Effect of Power Availability from Syngas on the Required Power Selling Price for a 12% Return on Investment

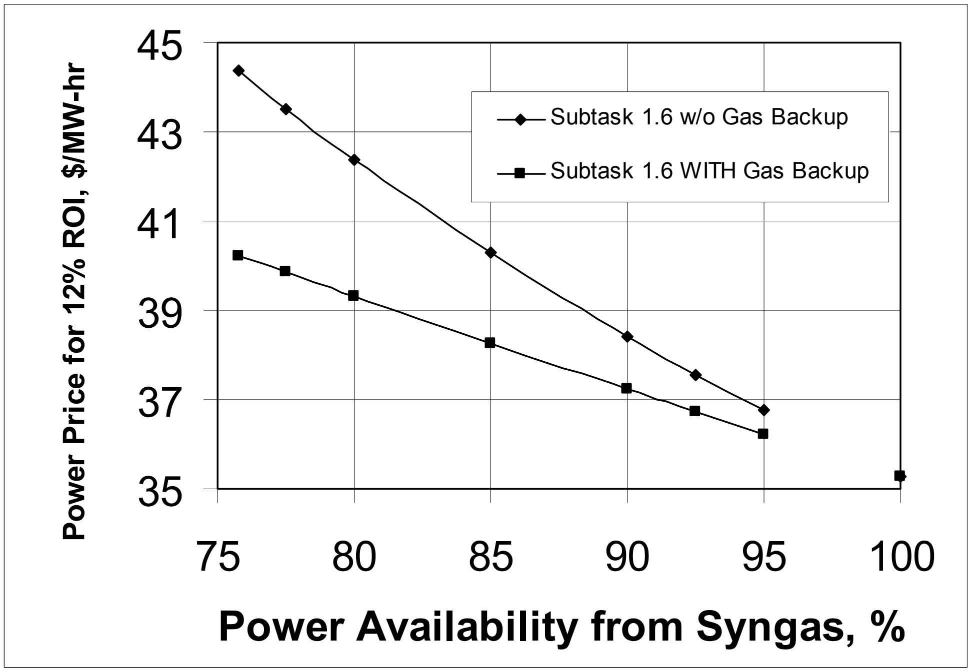


Figure 11

Effect of Power Availability from Syngas on the Return on Investment Without Gas backup at a Power Selling Price of 44.37 $/MW-hr

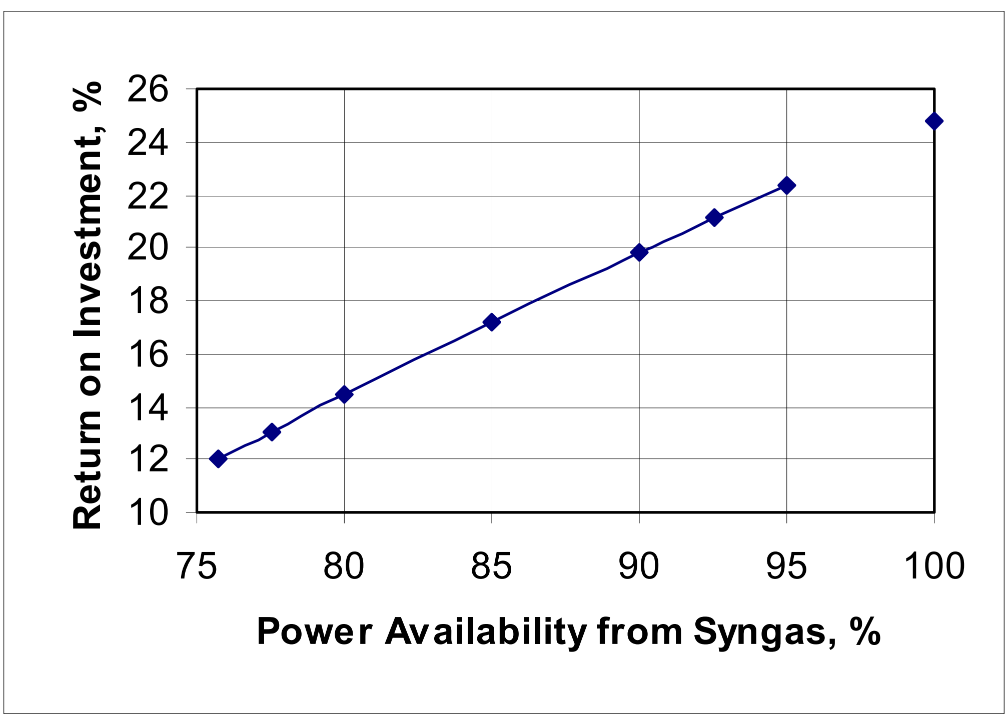


Figure 12

Effect of Power Selling Price on the Return on Investment at a 10% Loan Interest Rate for the Original Case (4 x 25% gasification trains) and for the Alternate Case (4 x 33% gasification trains)